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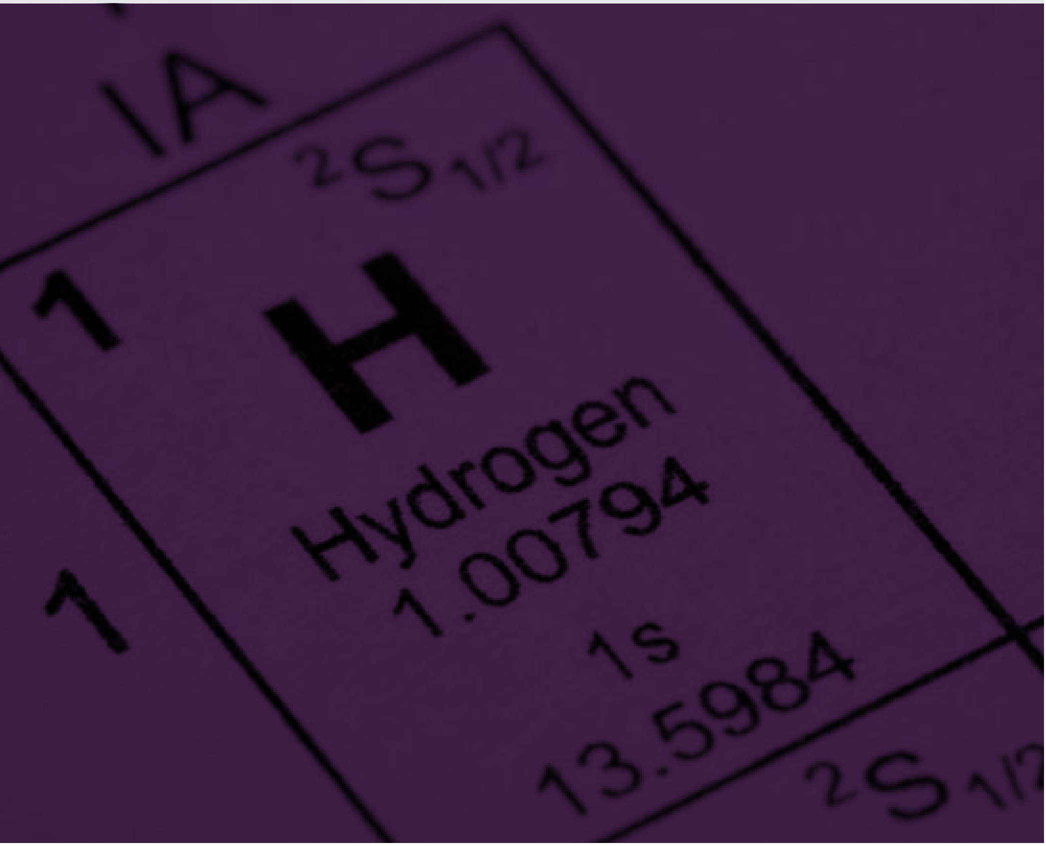
An insights report by the
Energy Technologies Institute

Hydrogen
The role of hydrogen storage in a clean responsive power system



The ETI has completed an assessment of the potential of using salt caverns, traditionally used to store natural gas, to store hydrogen (H_2) for power generation when the demand for electricity peaks daily. The use of these caverns would reduce the investment in clean power station capacity that the nation requires to build, and lift the average efficiency of the country's responsive power system.

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Key headlines

- Using salt caverns to store hydrogen has the potential to deliver clean, grid-scale load-following energy supplies
- The potential to store hydrogen changes inflexible gasification and reforming technology into competitive, highly flexible options for load following fossil fuel, biomass and waste fed power stations
- The UK has sufficient salt bed resource to provide tens of 'GWe'* to the grid on a load following basis from H_2 turbines
- Technologies making hydrogen from methane, such as steam methane reforming (SMR) and autothermal reforming (ATR) need to improve if they are to be competitve in power production from 100% hydrogen storage configurations – much of this improvement is already in hand in national clean fossil fuel, Carbon Capture and Storage and turbine technology development programs
- Pre-combustion technology with storage offers flexibility to produce hydrogen and reduce the overall power generation investments

"The UK has sufficient salt bed resource to provide tens of 'GWe'* to the grid on a load following basis from H_2 turbines"

* GWe = Gigawatt of electricity, GWhe = Gigawatt hours of electricity

The role of fossil fuel power stations

- New renewable power supplies are intermittent which increases the need for a low cost 'on demand' supply
- Operating fossil fuel power stations at lower loads reduces their efficiency and increases capital costs per MWh produced
- ETI believes that CCS technologies have the potential to show adequate flexibility in load-following mode

The role of fossil fuel power stations in the mix of UK power production has traditionally been threefold:

- To support nuclear in producing base load generation at low cost
- To follow the changing daily demand for power – to load follow
- To provide short bursts of power to cope with temporary demand peaks at very short notice (minutes)

As the UK invests in lowering its national carbon footprint, more and more renewable power supplies (wind, solar) are being built and put on the grid. However, although clean, these new supplies are intermittent, which increases the need for a low cost 'on demand' power supply that currently only fossil fuel plants can satisfy. Power produced from this fleet of fossil fuel plants will diminish and eventually only plants fitted with Carbon Capture and Storage (CCS) will be built. Unfortunately, operating fossil fuel power stations at lower loads reduces their efficiency (more CO_2 is produced per MWh) and increases capital costs per MWh produced, both of which are aggravated by fitting CCS equipment. When run at full load, stations with CCS will offer competitive clean power, but a high proportion of the power we produce (30-40%) is in the load following mode. This must have low emissions if the UK is to reach it's 2050 climate change targets.

Therefore CCS plants must eventually show similar flexibility to today's mainstay combined cycle gas turbine (CCGT) products, which strive for good start up and low load performance characteristics in addition to ever higher efficiencies. Coal stations have also developed flexibility, with the exception of gasifiers (Integrated Gasification Combined Cycle – IGCCs) which cannot be ramped up quickly and have a limited ability to operate at low load.

After undertaking dispatch analysis, the ETI believes that CCS technologies have the potential to show adequate flexibility in load-following mode. The main challenge for large scale roll out is the combination of:

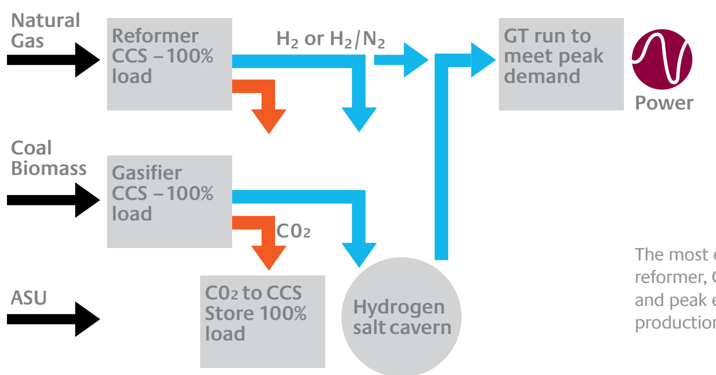
- Added capital cost for CO_2 separation, compression, transportation and storage, which would sit idle most of the time
- Energy losses associated with running carbon capture equipment especially at low load

The ETI has evaluated configurations which use hydrogen storage and turbines to see if storage could reduce the cost of the idled asset in a load following power system. In one such configuration, shown in Figure 1, a gasifier (coal and/or biomass) or steam reformer (methane gas) runs continuously, feeding H_2 to a salt cavern when power is not needed, and feeding the turbine when power is needed. The gas turbine (GT) is capable of burning much more than the instantaneous output of the H_2 plant. The store then co-feeds the turbine at peak demand periods to fill the turbine capacity. Since H_2 production uses a lot of electricity, this could be optionally increased at night when power is cheap.

The ETI appointed Amec Foster Wheeler and the British Geological Survey to complete a techno-economic study 'Hydrogen Storage and Flexible Turbine Systems' which has informed our thinking in this subject.

FIGURE 1

Power station configurations using H_2 storage



The most expensive assets (gasifier, reformer, CCS) all 'sweat' at 100% load and peak efficiency, even though power production varies.

H_2 storage in salt caverns

- Salt caverns are man-made underground holes created by washing salt out of large geological structures made of almost pure salt
- Used throughout the world to store natural gas and other hydrocarbon products
- Viable stores exist in the UK at various depths, down to more than 2000 meters deep
- UK's largest caverns are over 600,000m³

Salt caverns are man-made underground holes created by washing salt out of large geological structures made of almost pure salt. As shown in Figure 2 a well is drilled down into the salt field. Water is pumped down, dissolves the salt, and the brine removed for use or disposal. They are used throughout the world to store natural gas and other hydrocarbon products. The UK stores about 10,000 GWh of natural gas alone (enough to keep the country running for a few days). H_2 is also currently stored in a small number of salt caverns in the UK and the USA, supporting chemical plants and oil refineries. The largest single store (USA) holds over 100GWh of H_2[1].

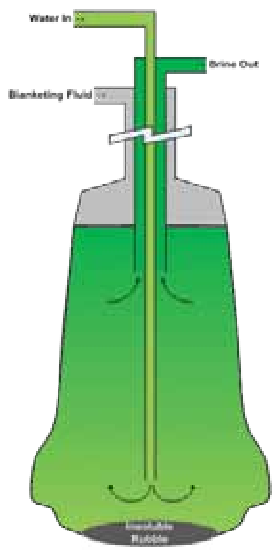
In Germany[2] air is compressed overnight and pumped into a salt cavern to feed a gas turbine which supplies power at peak times during the day. This demonstrates the ability of a cavern to operate in a 'daily' filling and emptying mode. Several gas stores in the UK can also release very large flowrates of gas to the grid to meet peak demands.

Most stores are operated by filling them to a pressure, usually 80% of the surrounding rock formation pressure, and then reducing pressure by the removal of gas to a minimum of about 30% of the formation pressure. Formation pressures vary with store depth, with viable stores in the UK more than 2000 meters deep at pressures over 270 Barg.

The cavern size and shape can be restricted primarily by the salt thickness. The UK's largest caverns are about 600,000m³ (e.g. 100m diameter by 100m high)[3].

FIGURE 2

Creating a salt cavern



Courtesy BGS

600,000m³

The UK's largest caverns are over 600,000m³

[1] Hydrogen as energy storage medium and fuel for transport, U Bunger, Trondheim 2012

[2] Crotogino, Fritz, Klaus-Uwe Mohmeyer, and Roland Scharf. 'Huntorf CAES: More than 20 Years of Successful Operation.' Natural Gas 45.50(2001):55

[3] Memorandum submitted by British Geological Survey www.parliment.uk

The UK resource

- Over 30 large caverns in use in the UK
- Detailed analysis of UK salt fields are available
- The peak demands of a whole city could be catered for by a single cavern
- Caverns have a long successful history in several different storage roles including seasonal, diurnal, and rapid response and handling various liquids and gases, including H_2
- Stores are of impactful size both for 'on demand power' and providing 'reserves'
- Salt beds are not widespread, but are located in good locations

There are over 30 large caverns in use in the UK spread over several locations, principally in those areas shown in yellow in Figure 3.[3] BGS have provided a detailed analysis of the salt deposit thickness, depth and quality (in terms of intrusions of 'layers of impurity' in the salt bed) of these and smaller deposits. It should be noted that within the areas shown in yellow the bed thicknesses vary greatly. Considerable additional capacity is currently being planned.

Three areas were selected for techno-economic modelling:

1. A shallow field in Teesside
2. A deep field covering East Yorkshire
3. An intermediate field such as in Cheshire

Fields of different depth were chosen because as depth increases, the storage pressure increases. This means the stores can hold more gas, but expensive compression equipment is needed to pressurise the gas into the cavern.

Screening work revealed that for the shallowest salt bed (Teesside) a large number of stores (about 20) would be needed to fill a large turbine (a gas turbine and heat recovery steam generator (HRSG) set rated at c.400MWe) operating at a load factor of 36%. A load factor of 36% was taken as representative of a station running during the working day, but off at night and weekends.

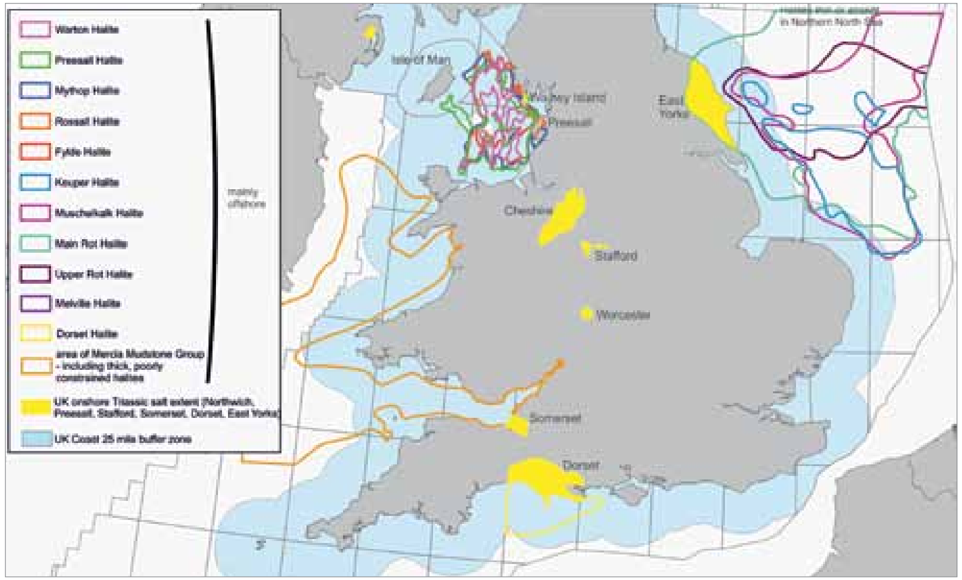
In the deepest salt bed modelled by the ETI (East Yorkshire) a single cavern could satisfy the turbine and HRSG. In fact a set of six caverns holding H_2 (and Nitrogen (N_2)) used to control combustion) could hold 600 GWh of H_2, yielding approximately 150 GWhe of energy accessible on a seasonal basis or 30 GWhe available on a daily basis (comparable to all our current pumped hydro storage systems). The peak demands of a whole city could be catered for by a single cavern.

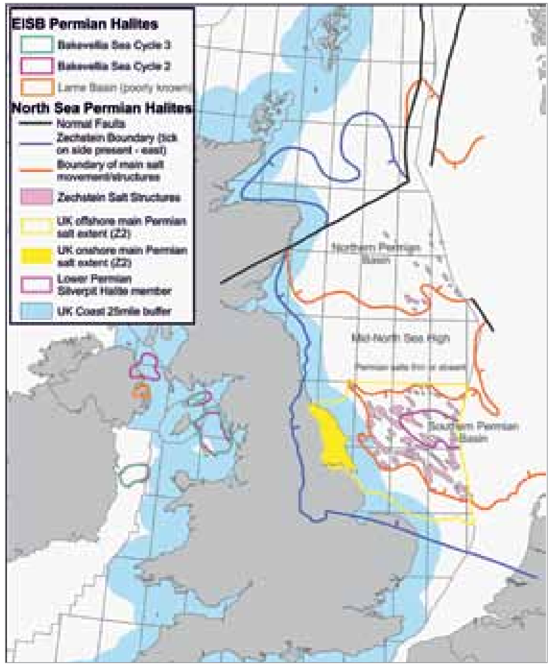
[3] Memorandum submitted by the British Geological Survey www.parliment.uk

FIGURE 3

UK salt fields shown in yellow, Triassic (top) and Permian

Courtesy BGS





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There are over 30 large caverns in use in the UK spread over several locations

Converting fossil fuel to H_2 and burning H_2 for power

- H_2 manufacture is a mature technology
- Making H_2 from coal (optionally mixed with biomass) and then combusting the H_2 causes no cost or efficiency penalty difference compared to conventional power production
- Making H_2 from methane and then combusting the H_2 adds cost and causes a loss in efficiency compared to 'conventional' clean power production (CCGT/CCS)
- Impactful technology improvements are being tested in the US and Europe
- For 100% H_2 combustion, N_2 or steam diluent is needed. This increases complexity

Power is produced from coal (and optionally biomass) using a number of different technologies:

- Combusting coal in air, raising steam and expanding the steam in a steam turbine
- Combusting coal in oxygen, raising steam and expanding the steam in a steam turbine
- Creating H_2 from coal by reacting it with a limited amount of oxygen (termed 'gasification') and then burning that H_2 in a gas turbine

In a world where CCS has to be fitted to coal stations, there is no cost penalty in the gasification route (H_2), either in capex or efficiency. This is because all three routes from coal to power as described have similar efficiencies, about 35%* in converting the energy in coal to electricity. The gasification plant is less flexible than the combustion route, as both the gasifier and its oxygen supply plants can change output at only a few percent per minute, so are not good load followers, and in any case do not turn down to low loads easily.

In today's market, power produced from methane gas uses CCGT technology and these plants can also be fitted with post combustion CCS and still retain a high efficiency of 50%. With today's technology, making H_2 as a intermediate in a reformer or partial oxidiser (with CCS) incurs an additional efficiency penalty, stemming largely from losses in converting the methane to H_2 and purifying it. Therefore, unless the H_2 producing schemes get revenue from supplemental H_2 sales (say for transport or chemicals) the next set of gas fired power stations, supported by Contracts for Difference (CFDs), will favour designs which are designed to burn methane, not H_2. However, the transitional pathway to introduce H_2 from any new H_2 plants may be straightforward as some of the existing and new 'methane' fleet will be able to burn H_2/methane mixtures. Currently the ETI is operating a 4MW test unit to explore the safe working envelope of machines firing gases which contain high levels of H_2.

With regards the use of natural gas in power generation with CCS, recent R&D and demonstration units have narrowed the gap between pre-combustion and post combustion technologies, but many of these integrate the turbine and H_2 plant and so cannot be used in a plant such as shown in Figure 1.

H_2 is a much more reactive fuel than methane, with a very high flame velocity. Therefore machines designed for methane but burning 100% H_2 rely on dilution of the H_2 with N_2 or steam to control combustion.

Nitrogen is usually available as a byproduct of oxygen production (from air) which is needed for partial oxidation of the fuel, but in the schemes shown in Figure 1, H_2 use has been decoupled from N_2 production and so N_2 has to be stored. Steam is also an effective diluent, with some advantages for a load – following unit, but might increase maintenance costs of the plant.

Recognising that cheaper and more efficient H_2 turbines would improve the economics of gasification – technology sums in excess of £100M[4] are going into development and improvement programmes. Vendors are approving use of their GTs with modest amounts of H_2 in the fuel (c.25%), and improving existing designs to cope with higher H_2 content fuels. Several, however, start up with methane and switch to H_2 when stable. Similarly, highly efficient processing and separations are being explored and tested e.g. by the European 'Cachet 1 & 2' natural gas processes and US DOE clean coal programs[5].

* All efficiencies quoted are based on the lower heating value of the fuel – i.e. LHV

[4] www.netl.doe.gov/publications/proceedings/10/utsr/presentations/tuesday/Dennis.pdf

[5] Cachet 11 Report Summary at http://cordis.europa.eu

Economics of different power production methods using H_2

- Viewed from a high level there is no clear winner for fuel or technology choice on a 100% load, no store option basis
- At lower loads (and certainly less than 40%) the configuration with stores is cheaper
- The gas price largely determines the break point at which the H_2 and storage combination becomes the better option. For the coal/biomass option fuel is a relatively smaller contributor to overall cost
- The ability to dilute the H_2 with steam rather than N_2 is an important option for all GTs – further work is needed to explore how this improves flexibility and LCoE at low loads
- As loads drop, aero derivatives and open cycle machines will become cost effective for H_2 fuelled GTs
- A full dispatch analysis is needed to tune findings

The costs of converting coal, coal/biomass and natural gas to H_2 with CCS and then power have been produced by Amec Foster Wheeler to provide 'order of magnitude' capital and levelised cost. When viewed from a high level, there is no clear winner for fuel or technology choice on a 100% load, no store option basis. For mid-point 'UK' (Department of energy and Climate Change) primary fuel prices, the solid fuels have a slight levelised cost advantage.

A table of the main statistics for the studied technologies assessed are provided in Appendix 1. The capital and efficiency advantages normally enjoyed by methane over coal are compromised by the oxygen production, storage and H_2 manufacture. When N_2 is used as a fuel diluent for the turbine, the autothermal reforming route (ATR) shows a decisive efficiency improvement over steam methane reforming (SMR) (41% c.f. 33%). However, when in the steam reforming case the H_2 fed to the turbine is diluted with steam, not N_2, the cost of the air separation unit and N_2 storage could be eliminated and the SMR became competitive. Today, most of the world's H_2 is made from steam methane reforming, due to ease of supply, operation, lower environmental issues and cost, but adding CCS to SMRs erodes their advantage.

Other sources of H_2 such as electrolysis cannot compete on a pure cost basis with H_2 from fossil fuel with CCS. Only under conditions where an installed system can produce electrical power which has no market value (possibly due to excess wind and solar power being available at times of low demand) and has high availability to load up electrolysers can the costs to manufacture H_2 from power and water be competitive.

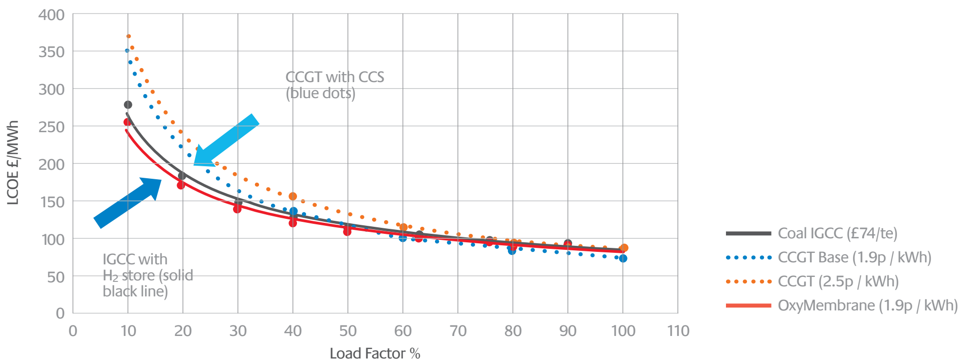
In Figure 4 the system costs are compared with the incumbent CCGT technology, fitted with post combustion CCS. At high turbine loads this is the best option for methane, but as the load drops the levelised costs increase quickly, as almost the entire capital spend is apportioned to diminishing production.
In the modelling, no correction was made for the deterioration in capture efficiency with reducing load so the results flatter the CCGT/CCS. However, systems with the store had better financials at low load, as most of the assets in this configuration are still 'sweating', with the exception of the turbines. The only technology in this set that is novel is the oxy-membrane, shown by the red line, which uses novel membranes to improve performance, as pursued by Europe's FP7 'Cachet' projects.

A desktop review of fuel cells technology as an alternative to turbines concluded that the cost and performance of these does not yet match the turbine, even though load following characteristics may be good. Several thousand alkali fuel cells, for example, would be needed to match the turbine output, and these need to be stacked and manifolded with low pressure, exceptionally pure H_2.

Solid oxide fuel cells, using hydrocarbon feeds and operating at high temperature, seem to offer more scope for good power cycle efficiencies.

FIGURE 4

Levelised cost changes with load factor



CCGT with CCS is compared to an IGCC with a H_2 store.
'Oxymembrane' means H_2 from methane by precombustion, with separation assisted by membrane (Cachet as noted above).

Fuel price assumptions shown in brackets. Detailed assumptions in Appendix 1.

The economics of the salt caverns

- Onshore cavern costs are modest compared to other cost blocks in the system
- A 300,000m^3 fast fill cavern in Yorkshire costs about £200m, most of which is surface facilities
- Offshore caverns are markedly more expensive than onshore ones. Only if very large quantities of storage is required (e.g. the Gateway proposal[6] in Merseyside) would these be especially attractive
- The shallow, thinner 'Teesside' field is borderline as a location for a H_2 store for a large power installation due to the large number of caverns needed, and the area of land needed for development

The three fields examined by the ETI research have very different depths (and so different storage pressures) and have different store sizes due to salt thickness and depth. The cost structures are very different in their makeup, but the total costs are very similar. As shown in Figure 5 and Appendix 2, the costs of shallow stores are dominated by cavern construction costs, and have lesser 'surface facility' equipment. These would be expensive 'strategic storage,' requiring an infeasible number of caverns for 'monthly' regimes. Nevertheless these smaller stores could still participate in clean technology options for example by storing synthetic natural gas made from biomass or waste (natural gas has about 5 times the energy density of H_2).

By contrast the deep stores have very high topside costs to compress the H_2 from 20-60 Barg up to the storage pressure of 270 Barg. They incur losses as the gases are spilled and turbo expanded down into the turbine. This round trip causes an expensive 2.5% (LHV) hit, in a scheme which is about 35% efficient (LHV). There are currently no high pressure expanders on the market to completely elimate this loss. The Cheshire caverns are arguably a good compromise.

With today's GT's the need to dilute the H_2 with N_2 doubles the cavern cost contribution, which is significant but not fatal to the economics. Even at low turbine utilisations and with N_2 co-storage the caverns cost less than half of the turbine costs.

Fast filling and emptying stresses the walls of the cavern, and the pressure range and annual turnovers are restricted to reduce this. For 'daily' operation for example, only 10% of the cavern pressure (or 10% of the volume, termed the 'working volume') may be useable each day. The remaining 90% of the gas which has to stay in the cavern is called 'cushion gas' and is capitalised. For slower removal rates, higher pressure ranges are technically acceptable and over 50% of the cavern pressure may be useable. The deeper caverns studied could offer reasonable longer term storage costs, as the surface facility cost would reduce and the working volumes would be a higher percentage of the cavern volume.

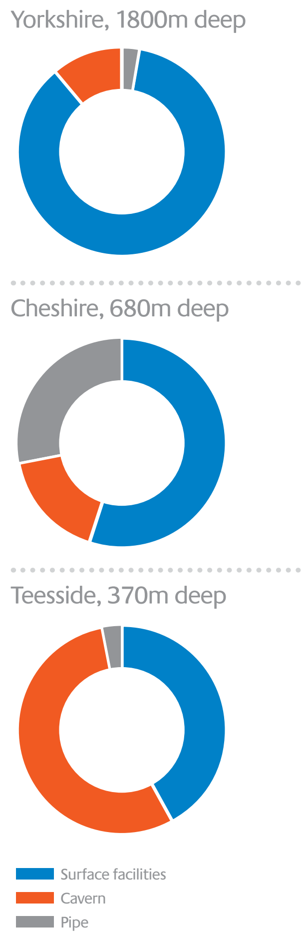
The largest element of the 'underground' costs of cavern construction is construction of the well, so caverns tend to be the largest possible size feasible within the salt structure.

£200m

A 300,000m^3 fast fill cavern in Yorkshire costs about £200m, most of which is surface facilities

FIGURE 5

Distribution of principle costs for different stores



[6] The Gateway Project at http://www.gatewaystorage.co.uk

Benefits to the energy system

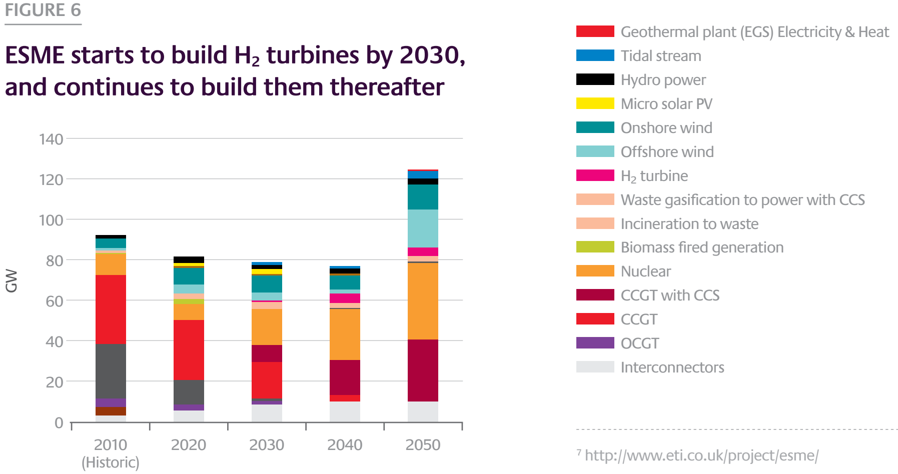
» H_2 storage and turbines could offer significant system level cost benefits over other storage approaches and reduce the cost of the clean new capacity needed by the UK to meet its emission targets

The potential role for hydrogen stores in the power sector can be illustrated by including the option in the ETI's energy system modelling (ESME)[7] tool – a national energy system design and planning capability. ESME works out the mix of technologies which enables the UK to comply with its 2050 climate change targets at the lowest cost. When the cost figures provided by this exercise were fed into ESME, H_2 stores were adopted by 2030.

The stores run at moderate load when new, but over time the load factors are reduced. ESME continues to build and use them out to 2050. CCGT with CCS retains leadership operating at higher load factors, as expected from a simple levelised cost analysis. The modelling shows the increasing need and value for flexibility in the system as nuclear and wind are deployed out to 2050. A market which rewards this flexibility is needed to reflect this requirement. In scenarios with higher intermittent generation, the demand for H_2 turbines grows to around 20GW. Smaller quantities of H_2 are fed to industry and possibly also the transportation sector for use in fuel cell vehicles. ESME favours biomass in the feedstock for H_2, in spite of the extra costs, because in effect CO_2 is removed from the air and the CCS is burying it – effectively producing 'negative emissions' for power production.

FIGURE 6

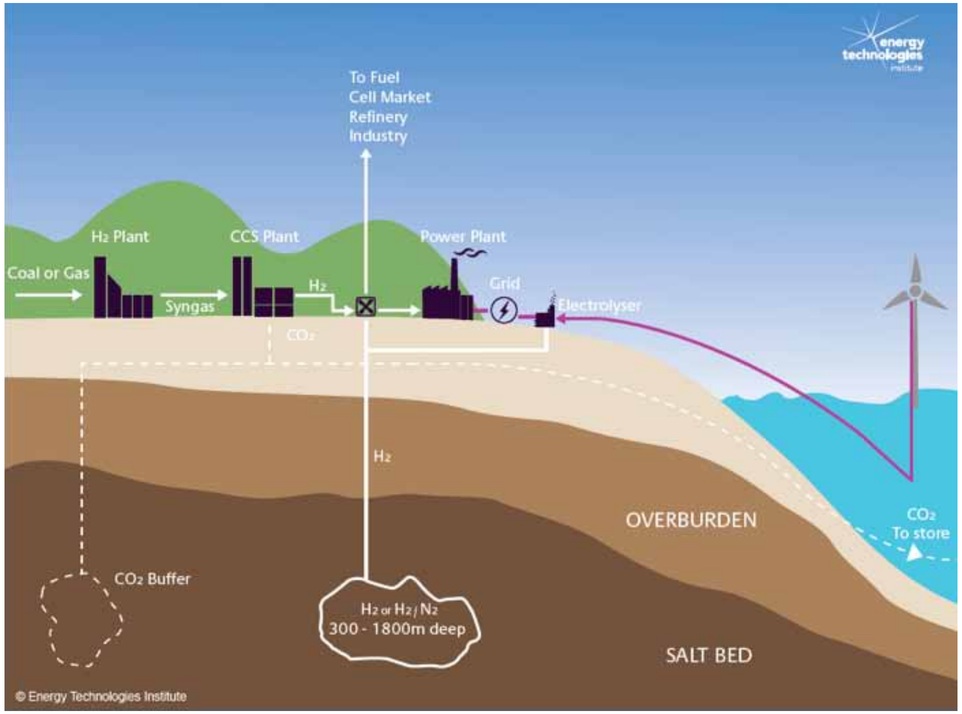
ESME starts to build H_2 turbines by 2030, and continues to build them thereafter



[7] http://www.eti.co.uk/project/esme/

FIGURE 7

H_2 storage and a clean, responsive power system



Optional CO_2 buffer storage is shown, to levelise any changes in CO_2 supply to the store caused by other users.

Appendix 1

Summary of performance of power generation via H_2

Technology	H_2 plant capex (no storage, no contingency) Million £	Efficiency (no storage)	LCOE 36% Load (as a power plant) £/MWh	LCOE 100% Load £/MWh
Coal Gasification	1230.4	34.4	136.8	77.4
Coal/Biomass Gasification	1246.5	33.9	143.1	85.7
ATR	1176.2	41.12	147.4	93.5
SMR	741.84	33.1	160	105
SMR w/Steam	717.35	35.77	151.5	97.8
CCGT with CCS		48.8	140	74.1

Gas Price 1.9p/kWh
Coal Price £74/te
Biomass Price £120/te

Project Life – 30 years
Salt Cavern Location – Yorkshire
Number of Gas Turbines – 4 for 1.3GWe
Storage Type – Co-storage of H_2 and N_2
CO_2 Disposal Cost £10/te
Contingency 25%

Appendix 2

Cavern capital costs for 400 MWe (gross) GT and HRSG at 36% turbine load factor

		Onshore			Offshore
		Teesside	Cheshire Basin	East Yorkshire	East Irish Sea
Salt Cavern storage size	m^3	70,000	300,000	300,000	300,000
Salt cavern depth	m	370	680	1800	680
Salt cavern operating pressure	bara	45	105	270	105
Number of cavern required for weekly operational mode and with combined storage		21	3	1	3
Water / Brine pipeline length	km	5	61	5	1
Costs					
Jack-up drilling rig hiring cost	Million £	–	–	–	5.2
Specialist drilling equipment hiring cost	Million £	–	–	–	1.2
Geological survey cost	Million £	3.0	3.0	3.0	6.0
Salt cavern construction cost	Million £	128.5	39.3	26.8	39.3
Water pipeline cost	Million £	2.7	33.2	2.7	0.5
Brine pipeline cost	Million £	2.7	33.2	2.7	0.5
Costs of a 4 legged tower 'Jacket' structure	Million £	–	–	–	18.8
Install cost of topside and above ground facility	Million £	97.1	130.2	205.9	350.8
Land costs (5%)	Million £	11.7	11.9	12.1	20.8
Owners costs (10%)	Million £	23.4	23.9	24.1	41.6
Contingency (25%)	Million £	58.5	59.7	60.3	104.0
Cost of production of cushion gas	Million £	1.4	1.8	2.2	1.8
Total project cost	Million £	329.0	336.4	339.9	590.5

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